EXHIBIT C

Energy Intelligence www.energyintel.com

NATURAL GAS WEEK®

Vol. XXXI, No. 50 30th Anniversary December 14, 2015

NATURAL GAS WEEKLY SPOT PRICES

Flow Dates: 12/8-12/14

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Dec. Bid Week
GULF COAST							
ANR SE	1.81	-0.27	2.00	1.64	66,936	10	2.15
Col. Gulf - Erath	1.79	-0.29	1.98	1.65	48,914	5	2.14
Col. Gulf - Rayne	1.75	-0.31	1.98	1.66	195,136	18	2.12
Florida Zone 1	—	—	—	—	—	—	2.21
Florida Zone 2	—	—	—	—	—	—	2.30
Florida Zone 3	1.89	-0.26	2.08	1.70	86,997	10	2.23
Henry Hub	1.94	-0.17	2.05	1.75	46,071	6	2.21
NGPL-LA	—	—	—	—	—	—	—
Sonat	1.80	-0.29	2.04	1.64	175,693	18	2.18
Tenn 500 So LA Z1	1.75	-0.35	2.05	1.64	75,601	11	2.16
Tenn 800 So LA Z1	1.93	-0.15	2.01	1.67	32,400	6	2.15
Tetco ELA	1.73	-0.31	1.96	1.64	64,186	8	2.10
Tetco WLA	1.76	-0.32	1.96	1.67	77,729	7	—
TGT Zone SL	1.81	-0.22	1.94	1.73	314	1	2.15
Transco Station 45	1.99	-0.11	2.07	1.83	2,971	1	—
Transco Station 65	1.79	-0.32	2.06	1.66	104,510	14	2.20
Trunkline ELA	1.88	-0.22	1.93	1.84	1,429	1	2.19
Trunkline WLA	—	—	—	—	—	—	—
Trunkline Zone 1A	1.73	-0.33	2.00	1.66	64,771	6	2.14
Regional Average	1.79	-0.29					2.17
TEXAS (SOUTH/EAST)							
Carthage Hub	1.81	-0.26	2.00	1.65	38,886	4	—
HSC	1.79	-0.37	2.06	1.73	52,500	4	2.19
Katy Hub	1.83	-0.32	2.04	1.75	94,886	9	—
NGPL-South Texas	1.77	-0.30	1.96	1.67	22,614	2	2.13
NGPL-TexOk	1.76	-0.33	1.98	1.67	155,157	16	2.13
Tenn Zone 0	1.88	-0.17	1.98	1.84	2,571	1	2.12
Tetco-East Texas	1.93	-0.11	1.96	1.78	386	1	—
Tetco-South Texas	1.78	-0.31	1.98	1.68	32,443	3	2.13
TGT Zone 1	1.82	-0.25	1.98	1.65	33,943	7	2.13
Transco Station 30	1.84	-0.27	2.05	1.65	17,657	3	2.14
Regional Average	1.79	-0.31	—	—	—	—	2.14
TEXAS (WEST)							
El Paso Permian	1.84	-0.28	2.03	1.65	296,786	35	2.15
NNG Custer	—	—	—	—	—	—	—
Transwes E of Thoreau	1.79	-0.33	2.02	1.69	85,929	12	2.07
Waha Hub	1.81	-0.29	2.01	1.64	166,357	17	2.10
Regional Average	1.82	-0.29					2.14
MIDCONTINENT							
ANR SW	1.76	-0.36	1.91	1.65	20,771	2	2.11
CenterPoint East	1.79	-0.29	1.98	1.60	47,571	5	2.08
CenterPoint West	—	—	—	—	—	—	—
NGPL-MC	1.79	-0.31	1.93	1.68	28,086	4	2.12
Oneok	1.58	-0.49	1.91	1.54	28,286	2	2.07
Panhandle	1.63	-0.43	1.92	1.50	76,905	10	2.09
Southern Star	1.78	-0.28	1.95	1.60	41,830	6	2.06
Regional Average	1.71	-0.36					2.07
GREAT PLAINS							
Emerson	1.88	-0.24	2.09	1.68	112,450	20	2.49
NB Ventura TP	1.78	-0.32	2.04	1.70	146,814	6	—
NNG Demarc	1.82	-0.27	2.01	1.70	86,664	8	2.31
NNG Ventura	1.82	-0.37	2.04	1.71	143,743	10	2.32
Regional Average	1.82	-0.30	—	—	—	—	2.32

(continued on p.2)

Industry Hits EPA's Methane Rule as Study Details Leaks In Texas

Gas industry groups last week stepped up their fight against a federal proposal to reduce methane emissions, arguing in filed comments that the US Environmental Protection Agency (EPA) risks harming producers' ongoing ability to produce gas cheaply. But some environmental and health organizations urged the EPA to impose even stronger measures to cap methane leaks.

The comments came as a new study sponsored by the Environmental Defense Fund (EDF) showed methane emissions in the gas-rich Barnett Shale of North Texas are much greater than EPA data suggests.

(continued on page 15)

Texas Energy Snapshot Continues 11-Month Collapse, No End Seen

For the past 11 months, the Texas Petro Index (TPI) has shown an industry reeling from the cumulative effects of the global downturn and, according to the economist who created the monthly snapshot of the Texas energy industry 20 years ago, there's no end in sight.

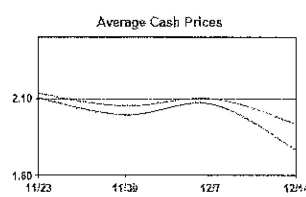
The TPI declined for the 11th straight month in October, to 212.3, 32.2% less than in October 2014 when the index reached a record 313.2. And again, all TPI indicators decline in October except natural gas and crude oil production.

October natural gas production reached 753.4 billion cubic feet — a year-over-year monthly increase of 1.7%. There was

(continued on page 14)

US January Futures Drop Below $2, Henry Hub Cash Hits 14-Year Low

It looks like North American gas producers will be getting a lump of coal in their stockings this year, as the cash and futures markets careened to lows below $2 per million Btu last week in a move reminiscent of the darkest days of the 1990s gas glut. Only this time it could be worse.



Storage is at record levels and demand has practically flat-lined in the major eastern US markets. Bearish senti-

(continued on page 7)

NATURAL GAS WEEKLY SPOT PRICES (cont.)

Flow Dates: 12/8-12/14

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Dec. Bid Week
UPPER MIDWEST							
Alliance	1.81	-0.36	2.03	1.73	29,657	2	—
ANR ML7	1.98	-0.30	2.27	1.74	5,938	5	2.52
Chicago Citygate	1.84	-0.31	2.08	1.70	192,061	22	2.42
Consumers	1.86	-0.30	2.14	1.74	109,397	20	2.42
MichCon	1.83	-0.37	2.10	1.74	234,941	32	2.40
Regional Average	1.84	-0.33	—	—	—	—	2.41
SOUTHEAST							
Tetco M1	1.70	-0.35	1.96	1.63	15,871	2	2.08
Transco Zone 4	1.81	-0.34	2.09	1.64	248,409	24	2.22
Transco Zone 5	1.77	-0.42	2.17	1.65	81,824	9	2.66
Regional Average	1.80	-0.36	—	—	—	—	2.31
APPALACHIA							
Col. Gas App. Pool	1.72	-0.31	1.95	1.58	22,944	9	2.05
Dominion North	0.98	-0.22	1.36	0.70	8,134	3	1.48
Dominion South	0.88	-0.34	1.37	0.55	133,149	20	1.49
Lebanon Hub	1.79	-0.32	2.04	1.65	136,435	7	2.27
Regional Average	1.36	-0.24	—	—	—	—	1.76
EASTERN CANADA							
Dawn	1.87	-0.31	2.14	1.74	430,600	50	2.49
Iroquois	1.65	-0.58	2.25	1.15	132,616	23	3.19
Niagara	1.15	—	1.30	1.05	143	1	2.53
Regional Average	1.82	-0.37	—	—	—	—	2.62
NORTHEAST / MIDATLANTIC							
Algonquin	1.33	-0.96	2.80	0.90	106,330	19	5.21
Dracut	—	—	—	—	—	—	—
Iroquois Zone 2	1.59	-0.65	2.26	1.10	36,549	11	3.65
Tenn Gas Zone 6	1.76	-0.68	2.70	0.84	43,043	7	5.02
Tetco M3	0.92	-0.40	1.52	0.66	151,035	18	2.03
Transco Z6 - Non-NY	1.06	-0.81	2.10	0.85	104,386	6	2.76
Transco Z6 - NY	1.19	-0.75	2.10	0.82	80,790	10	3.02
Regional Average	1.19	-0.68	—	—	—	—	3.44
ROCKIES							
Cheyenne Hub	1.76	-0.28	1.93	1.68	107,414	9	2.11
CIG	1.73	-0.30	1.89	1.66	70,257	4	2.18
Kern River / Opal	1.84	-0.30	2.10	1.77	568,243	36	2.27
NW Rockies	1.82	-0.23	1.99	1.73	9,129	1	2.17
Questar	1.82	-0.22	1.95	1.73	18,629	1	2.10
Regional Average	1.82	-0.29	—	—	—	—	2.21
SAN JUAN BASIN							
El Paso Bondad	1.89	-0.23	2.01	1.76	29,171	3	—
El Paso San Juan	1.88	-0.29	2.02	1.73	97,343	14	2.19
Regional Average	1.88	-0.28	—	—	—	—	2.19
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	1.53	-0.07	1.61	1.50	985,650	46	1.80
Kingsgate	1.78	-0.18	1.84	1.77	41,629	2	—
Malin	2.01	-0.20	2.20	1.85	205,886	20	2.37
NW Sumas	1.88	-0.33	2.02	1.80	46,800	6	2.49
Stanfield	1.94	-0.22	2.04	1.84	38,286	5	—
Westcoast Station 2	0.81	-0.46	1.31	0.66	121,452	15	0.97
Regional Average	1.56	-0.23	—	—	—	—	1.80
CALIFORNIA							
Kern - Wheeler Ridge	—	—	—	—	—	—	—
PG&E Citygate	2.53	-0.09	2.59	2.45	98,100	7	2.64
PG&E South	2.02	-0.23	2.25	1.83	127,696	6	2.45
SoCal Border	2.06	-0.20	2.25	1.78	274,643	25	2.41
SoCal Citygate	2.20	-0.26	2.43	2.07	186,957	13	2.58
Regional Average	2.16	-0.28	—	—	—	—	2.58
WEEKLY COMPOSITE SPOT PRICES							
Wellhead	1.77	-0.30	—	—	—	—	—
Delivered	1.64	-0.39	—	—	—	—	—

Dow, DuPont Planning Mega-Merger Amid Shale Gas-Driven Resurgence

Dow Chemical and DuPont announced plans Friday to merge in a complex $130 billion deal, highlighting the US shale boom's impact on petrochemical companies that consume large volumes of natural gas as a feedstock.

The newly combined company, to be called DowDuPont, would then break into three separate publicly-traded entities focusing on agriculture, material science (including petrochemicals and plastics) and specialty products. The deal is expected to face tough scrutiny from antitrust regulators in the US and abroad.

"The stable, low natural gas prices created by the shale gas revolution have given US chemical manufacturers an enormous boost, leading to the construction of scores of new projects and expansions and dramatically changing the economics involved in their business," the Natural Gas Supply Association said Friday.

And in its *Short-Term Energy Outlook* last week, the US Energy Information Administration noted that industrial-sector gas consumption should grow 3.9% in 2016 to 21.7 billion cubic feet per day — 28% of total US demand — "as

(continued on page 3)

Pilot Program to Address Offshore Safety

The US Interior Department will soon select several offshore oil and gas operators to participate in a pilot program designed to increase the overall safety of those operations.

Interior's Bureau of Safety and Environmental Enforcement (BSEE) said the Risk-Based Inspection Program will complement its existing inspections and audits and more effectively manage limited resources by focusing on facilities most at risk of an accident.

"Risk factors include design, operating and environmental characteristics of the facility, which may correlate to a greater likelihood of experiencing an incident," BSEE Director Brian Salerno said. "However, it does not mean that the facility has a bad safety record or is a poor safety performer, only that certain risk factors are present that must be managed."

For the pilot program, BSEE will use performance and compliance data collected from annual inspections and audits as well as incident investigations and other reportable safety information to help identify offshore production facilities with a higher risk profile. Factors such as the size of the facility and the production of hydrogen sulfide are considered in developing the risk profile.

Participants in the pilot program will be notified within the next few weeks. BSEE plans to identify five facilities and then conduct focused inspections and reviews with an inspection team.

Once each inspection and review is completed, the BSEE team will review with operators the areas needing attention. Operators will be tasked with developing an action plan to solve any problems.

Elizabeth McGowen, Washington

Dow ...

(continued from page 2)

new industrial projects, particularly in the fertilizer and chemicals sectors, come on line."

Neither Dow nor DuPont on Friday mentioned energy costs as a driver behind the merger, but analysts have long said that a glut of gas and natural gas liquids (NGLs) created by the shale revolution (NGW Oct.26'15) will continue to bolster US-based petchem firms such as Dow, DuPont and LyondellBassell — especially in terms of cost advantages over their competitors in Europe and Asia.

Both Dow's and DuPont's plastics businesses have benefited from the oversupply and low cost of ethylene, an NGL used to make a host of plastics products. Yet their agricultural chemical businesses have suffered from low demand, a concern that helped accelerate the merger talks, Dow Chief Executive Andrew Liveris said Friday.

In March, Dow executive Doug May told a Chicago audience that the company – which had been moving some operations overseas — planned to expand its US manufacturing capacity by 40%, largely because Dow expects domestic gas and NGLs costs to remain relatively low for another 10 years.

"We're putting $6 billion here in the US Gulf Coast, betting that the gas advantage maintains for us to get a suitable return on that investment," Forbes quoted him as saying at the time. This includes a $4 billion expansion in Freeport, Texas, to add ethylene, polyethylene, propylene and plastics manufacturing capacity by late 2017.

Michigan-based Dow and Delaware-based DuPont, both of which have been in business since the 1800s, said the deal would create combined "synergies" of $3 billion, including staff cuts. Together the companies have more than 100,000 employees worldwide.

The merger still requires shareholder and regulatory approvals, with a targeted closing in the second half of 2016. The splits would then take place 18 to 24 months later.

Mark Davidson, Washington

Interior's Valuation Rule Doesn't Pass NatGas Industry's Sniff Test

Natural gas producers leasing on federal land and offshore waters fear a proposed regulation from the US Department of Interior will force them – indirectly – to pay higher royalty rates.

However, Interior's Office of Natural Resources Revenue (ONRR) says the updated rule is necessary to ensure that companies have paid every dollar due to the agency.

ONRR is modeling the rule — which would apply to natural gas, oil and coal — to match more functional and up-to-date royalty valuation regulations for oil, agency Director Gregory Gould told *Natural Gas Week.* He was in Washington to testify at an energy subcommittee hearing about the highly technical and complex draft rule last week.

Changes are long overdue because valuation regulations for natural gas and coal have been in place since the 1980s, he said, adding that they need to be brought into line with 21st century energy marketplace and business practices.

Conservation organizations, tax watchdogs and Democrat lawmakers have long contended that producers are not paying what they truly owe.

As directed by the Mineral Leasing Act, the US government charges a royalty rate of 12.5% to companies that extract coal, natural gas and oil from federal land.

While the draft rule would not alter that figure, the majority of natural gas producers sell to third parties, not subsidiaries. And they are on edge because the regulation does not address the controversial "unbundling" topic for sellers to third parties.

Traditionally, natural gas transportation and processing service providers have charged a single bundled fee for services, such as gathering, compression, dehydration and sweetening. Some of those lumped-together fees are deductible from royalty fees, but it's up to the producer to determine that percentage. Producers say they end up making royalty payments higher than 12.5% because so many fees aren't deductible.

An industry already besieged by low prices amid a market glut maintains that having to unbundle fees is a costly administrative burden that the proposed rule should eliminate.

ONRR disbursed $9.8 billion in annual revenues from royalty fees to states, tribes, individual Indian mine owners and the US Treasury in fiscal year 2105.

A final rule will not be released until next year, at the earliest. ONRR officials are still wading through the thousands of pages of feedback they received after rolling out the initial version in early January.

Three trade associations — the American Petroleum Institute, the Independent Petroleum Association of America and the National Ocean Industries Association — combined efforts to submit 28 pages of comments. They claim key facets of the proposed rule are "fundamentally flawed, lack a reasonable basis" and have "significantly understated the cost to industry."

"While we share ONRR's commitment to ensure a fair return to the public on production of oil and gas from federal leases, ONRR's proposal in several respects amounts to unjustified changes to the existing regulatory scheme in an unabashed attempt to benefit the federal coffers beyond the royalties fairly, and legally, due from federal lessees," they wrote.

Gould said his agency is continuing to listen to industry's ideas about tweaking the draft rule.

"We don't want to sell it short," he said about the rule. "We're sitting somewhere in the middle. And that's not a bad place for a regulator to be."

Elizabeth McGowan, Washington

INTRASTATE WEEKLY SPOT PRICES

Flow Dates: 12/8-12/14

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Dec. Bid Week
Louisiana Intras	—	—	—	—	—	—	—
Oklahoma Intras	1.580	-0.495	1.91	1.54	28,286	2	2.07
South Texas Intras	—	—	—	—	—	—	—
West Texas Intras	—	—	—	—	—	—	—

Gas Output Rises in North Dakota Due to Slug of Crude Production

Natural gas production increased in North Dakota for the first time in three months as operators ramped up production in anticipation to the recent Opec meeting.

Preliminary numbers show that the state's natural gas output — dominated by the Bakken Shale — rose by nearly 47 million cubic feet per day to 1.65 billion cubic feet per day in October, according to the latest data from the state Department of Mineral Resources (DMR).

Opec's inability to reach an agreement on an output cap at its semiannual meeting made many producers anxious of future commodity prices.

"A lot of operators were pretty pessimistic about the Opec meeting and they were right," DMR Director Lynn Helms said. "So they looked at October and November as an opportunity to produce and sell oil at what may have been seen as the high price for the next six months."

Additionally, new compression enhancements were brought on line that allowed a Oneok gas processing plant to operate at 10% above its listed capacity, which helped it to handle the spike in associated gas volumes.

Back in June, the state issued new regulations to cut gas flaring by 15% of total production by January 2016 (NGW Jun.16'14). However, as producers struggled to meet those requirements, the North Dakota Industrial Commission agreed to extend the deadline to November 2016 (NGW Sep.28'15).

In order to avoid more state imposed production restrictions, operators began enacting voluntary reduction regulations back in September, which involved temporarily taking a certain amount of wells off line (NGW Oct.19'15).

However, the statewide capture percentage for October was 86%, representing a 5% increase from the previous month.

With the gas capture target for the state currently at 77%, producers were able to bring some of those previously restricted wells back on line for the month.

However, Helms said, operating a processing plant that far above nameplate capacity is not a sustainable strategy with the coldest winter months approaching. But additional capacity is on the way.

"Lonesome Creek is on schedule and should be on and fully operational sometime in January," Helms said. "That's a 200 million [mcf/d] plant so it will relieve that pressure."

Tyler Webb, Houston

EIA Sees January Production Drop, But Supply Outlook Stays Muddled

While most producers are laying down rigs in the Appalachian Basin until gas prices recover and a few are even shutting in existing wells, EQT last week said it will drill 72 new Marcellus Shale wells next year and increase its annual production 20%.

The move by EQT — the first large E&P to spell out its 2016 drilling program — is among the many data points painting a somewhat confusing picture of the gas supply outlook for Appalachia and the rest of North America.

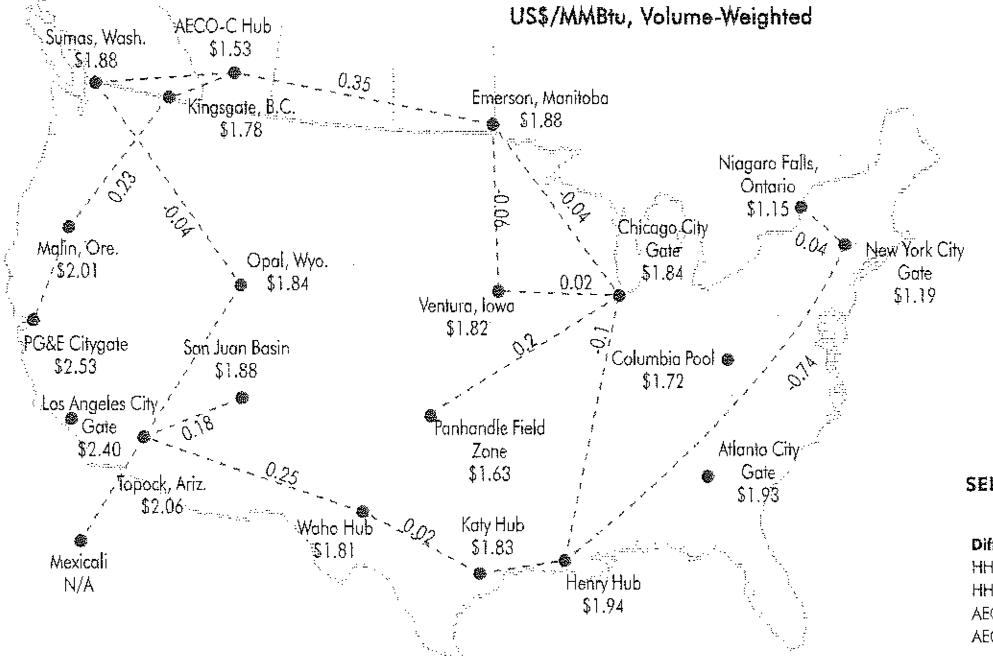
According to the US Energy Information Administration's (EIA) *Drilling Productivity Report* last week, gas production from the seven biggest unconventional basins will fall another 365 million cubic feet per day in January, nearly matching December's drop of 394 MMcf/d, as sup-

(continued on page 5)

PRICES AND DIFFERENTIALS FOR MAJOR HUBS AND SELECTED CITY GATES

December 14, 2015

US$/MMBtu, Volume-Weighted



SELECTED DAILY DIFFERENTIALS

Differential	12/7	12/8	12/9	12/10	12/11
HH-NY	+0.03	+0.04	-0.20	-0.56	-0.85
HH-Chicago	+0.01	+0.02	+0.04	+0.03	-0.02
AECO-CHIC	+0.50	+0.43	+0.46	+0.38	+0.22
AECO-PG&E	+1.04	+0.95	+1.00	+0.95	+0.93

Production ...

(continued from page 4)
ply finally begins responding to the sharp pullback in rig activity (NGW Nov.16'15).

More than half of that decline, or 213 MMcf/d, will come from the Marcellus (see chart), with another 172 MMcf/d drop is expected in the Eagle Ford Shale.

Yet in its *Short-Term Energy Outlook* released a day later, the EIA said it expects marketed gas production, which is up 6.3% this year, to rise another 1.9% in 2016 to 81.1 billion cubic feet per day, an all-time high.

The agency said increased drilling efficiencies "will continue to support growing natural gas production in the forecast despite low prices and declining rig activity" — with most of the growth occurring in the Marcellus. Indeed, the productivity report shows new-well output per rig in the Marcellus rising 128 MMcf/d in January after increasing in every month of 2015.

The EIA also cited increased output as "a backlog of uncompleted wells is reduced and as new pipelines come on line to deliver Marcellus natural gas to markets in the Northeast. Several major projects have recently come on line and a few others are set to begin service before the end of the year."

For EQT, plans to drill next year on its core Marcellus acreage stems in part from a well-hedged position. For 2016, it has more than a third of its gas volumes hedged through swaps at an average of $3.88 per million Btu — more than $1.50 above the current Nymex strip.

Gas Output From Major US Shale Regions

(MMcf/d)	December	January
Bakken	1,578	1,559
Eagle Ford	6,578	6,406
Haynesville	6,313	6,337
Marcellus	15,663	15,450
Niobrara	4,172	4,106
Permian	6,878	6,892
Utica	3,139	3,206
Total	**44,321**	**43,956**

Source: US Energy Information Administration

In 2016, EQT plans to drill 72 Marcellus wells with an average lateral length of 7,000 feet, "all of which will be on multi-well pads to maximize operational efficiency and well economics." As a result, EQT — the seventh-largest US gas producer — boosted its 2016 production guidance to 700 Bcf to 720 Bcf equivalent (1.92 Bcfe/d to 1.97 Bcfe/d), up from expected 2015 output of 575 Bcfe to 600 Bcfe (1.57 Bcfe/d to 1.64 Bcfe/d). About 99% of the company's production is gas.

Mark Davidson, Washington

Devon Said to Eye Small Oklahoma Stack Play Producer Felix Energy

US independent Devon Energy is reportedly courting private equity-backed E&P Felix Energy in a deal valued at about $2 billion, including assumption of debt.

The potential deal was first reported by Reuters, which cited "sources familiar with the matter." A Devon spokesman contacted by NGW sister publication *Oil Daily* declined to comment on the report.

Felix Energy is a Denver-based company with operations in the Anadarko Basin in Oklahoma. Most of its acreage is prospective to the Meramec and Woodford formations in the so-called Stack play area.

More specifically, its 75,000 net acres are concentrated in the oil window of the Stack play in Blaine, Kingfisher and Canadian counties, according to a presentation posted on its website.

The same presentation indicated that Felix has been running three drilling rigs in recent months and has identified roughly 1,000 horizontal drilling locations across its acreage.

Felix is backed by private equity firm EnCap Investments and currently produces about 8,000 barrels of oil equivalent per day (80% liquids).

In a message to clients, RBC Capital Markets analyst Scott Hanold noted that Felix's acreage overlaps Devon's acreage in the same area. Hanold said the reported value of the deal equated to a purchase price of around $20,000 per acre, adding that this was "reasonable for a core position but could be viewed as a bit 'rich' at current forward commodity prices."

With their investment-grade credit ratings, Devon and other large independents enjoy relatively easy access to capital during the current industry downturn compared to

(continued on page 6)

NORTH AMERICAN WEEKLY GAS STORAGE

(Billion Cubic Feet)

Region	Week Ending Dec. 4	Week Ending Nov. 27	% Full	1 Week Chg.	Year Ago	1 Yr Chg.	5 Yr Avg.	5 Yr Chg.
US								
East	910	919	85.0	(9)	819	91	872	38
Midwest	1,083	1,109	88.4	(26)	951	132	1,010	73
South Central	1,323	1,342	85.9	(19)	1,083	240	1,173	150
Mountain	203	211	43.7	(8)	173	30	202	1
Pacific	361	375	86.5	(14)	333	28	339	22
TOTAL LOWER 48	**3,880**	**3,956**	**82.2**	**(76)**	**3,359**	**521**	**3,596**	**284**
CANADA								
East	266	267	95.2	(1)	235	31	225	41
West	411	416	83.8	(6)	321	90	401	10
TOTAL CANADA	**676**	**682**	**88.0**	**(6)**	**556**	**120**	**622**	**54**
TOTAL NORTH AMERICA	**4,556**	**4,638**	**83.0**	**(82)**	**3,915**	**641**	**4,219**	**338**

Sources: US-EIA. Canada-Enerdata. Values in Bcf unless otherwise noted.

Devon ...

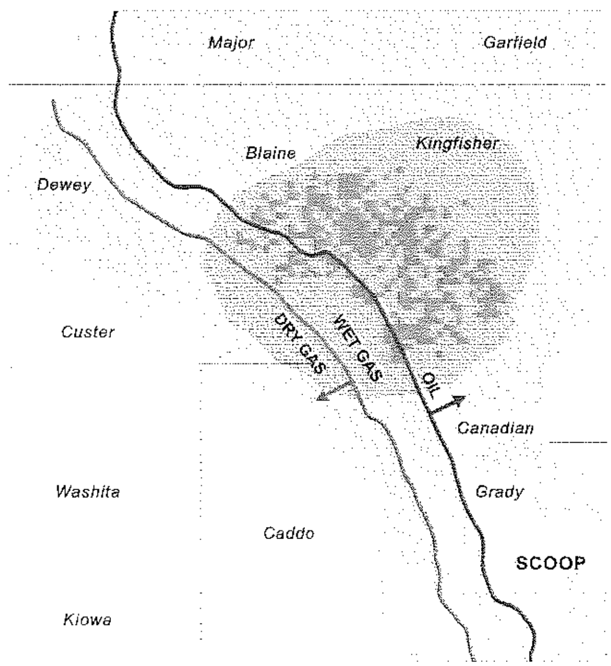
(continued from page 5)
smaller producers with speculative or "junk" credit ratings.

Devon reported cash-on-hand of about $1.8 billion at the end of the third quarter and was undrawn on its $3 billion credit facility.

The Oklahoma City-based company said in November that it expects "low single-digit" growth in its oil production next year as it cuts its upstream capital spending to $2 billion-$2.5 billion from $3.8 billion-$4.0 billion this year.

Jordan Daniel, Houston

FELIX ENERGY'S STACK ACREAGE



Felix Acreage Woodford Meramec

Source: Felix Energy

Kinder Morgan Ordered to Address Ned Objections, Cutting Dividend

Pipelines and energy infrastructure giant Kinder Morgan had something of rough time last week, as its controversial Northeast Energy Direct pipeline expansion continues to get pushback and shareholders were told that dividends were being cut.

The US Federal Energy Regulatory Commission has asked Kinder Morgan subsidiary Tennessee Gas Pipeline (TGP) to reply to a long list of letters from state and local officials, who have voiced concern over the company's proposed Ned project (NGW Nov.23'15).

In a letter dated Dec. 8, Ferc asked TGP to respond to at least 28 letters from local and state governments and the National Park Service about the project. Heading the list was a letter from the Massachusetts Attorney General's Office asking for a full study on the need for the project considering the amount of natural gas being brought into the area by other pipelines.

Ned is a 420-mile pipeline that would bring an additional 1.3 billion cubic feet per day of gas to New England markets and it would involve construction in Pennsylvania, New York, Massachusetts, Connecticut and New Hampshire.

Earlier last week, Kinder Morgan said it is slashing its dividend payment to shareholders in order to maintain its investment grade credit rating and fund growth projects without adding to its already heavy debt load.

The Houston-based company said it will reduce the quarterly dividend on its common stock by 75% — from 50¢ per share to 12.5¢ per share — beginning with its payout for the fourth quarter of this year.

Dividend payments will now total only $1.1 billion next year, rather than the $4.4 billion that it had previously indicated.

The move represents a striking reversal for Kinder Morgan, which since its founding 18 years ago has largely relied on loans to fund its growth projects while distributing the bulk of its cash flow to shareholders.

"This decision was not made lightly, but we believe it is in the best interests of the company, its shareholders and em-

(continued on page 7)

NATURAL GAS FUTURES

Trading Dates: December 7 - December 11

NEW YORK MERCANTILE EXCHANGE (NYMEX) (HENRY HUB)

	Monday		Tuesday		Wednesday		Thursday		Friday		Week's	Open
	Dec 7	Volume	Dec 8	Volume	Dec 9	Volume	Dec 10	Volume	Dec 11	Volume	Low-High	Interest
Jan 2016	2.067	188,741	2.070	172,495	2.062	153,581	2.015	186,400	1.990	—	1.959-2.162	243,310
Feb 2016	2.132	79,578	2.127	66,979	2.117	75,272	2.075	83,167	2.050	—	2.022-2.238	152,459
Mar 2016	2.174	79,421	2.171	70,433	2.162	67,842	2.129	79,820	2.107	—	2.081-2.252	199,156
Apr 2016	2.237	46,371	2.239	47,104	2.232	37,374	2.208	44,793	2.192	—	2.163-2.287	100,090
May 2016	2.291	18,256	2.297	26,906	2.292	16,851	2.270	16,969	2.254	—	2.227-2.332	57,426
Jun 2016	2.340	9,308	2.346	14,488	2.345	10,030	2.327	9,495	2.311	—	2.287-2.378	34,465
Jul 2016	2.390	7,518	2.397	13,962	2.399	9,721	2.384	10,396	2.366	—	2.345-2.430	24,198
Aug 2016	2.417	4,086	2.425	9,682	2.428	4,394	2.416	5,517	2.399	—	2.376-2.457	22,150
Sep 2016	2.422	7,524	2.432	11,493	2.437	9,248	2.426	8,248	2.409	—	2.383-2.470	34,568
Oct 2016	2.443	15,300	2.453	13,592	2.457	12,729	2.446	14,187	2.430	—	2.402-2.481	45,247
Nov 2016	2.529	1,550	2.534	1,336	2.539	383	2.576	990	2.509	—	2.484-2.557	13,122
Dec 2016	2.689	2,471	2.691	2,081	2.697	1,067	2.684	729	2.667	—	2.642-2.724	15,565
12-Mth Strip	**2.344**		**2.349**		**2.347**		**2.326**		**2.307**			
2016 Strip	2.344		2.349		2.347		2.326		2.307			
2017 Strip	2.740		2.745		2.750		2.745		2.737			
Total Volume		**464,912**		**457,071**		**403,539**		**467,847**		—		

Kinder ...

(continued from page 6)

ployees," said Kinder Morgan's co-founder and executive chairman, Rich Kinder.

"We evaluated numerous options, including significant asset sales, but ultimately concluded that these other options were uneconomic to our investors in the long run."

He framed the decision to lower the company's dividend as a choice between continuing its relatively lavish payouts to shareholders or being able to fund growth projects without having to take on increasingly expensive debt and risk losing its investment grade rating.

Kinder Morgan is a former master limited partnership (MLPs) and investors mostly continue to view it as such although it recently reorganized itself as a conventional corporation.

Midstream energy MLPs have traditionally attracted investors by paying steadily increasing dividends and growing their revenues through new infrastructure projects and acquisitions.

However, the steep drop in oil prices over the last year-and-a-half has reduced demand for new midstream capacity and made capital markets more cautious about lending money to energy companies.

Kinder Morgan's outsized long-term debt — which stood at more than $41 billion at the end of the third quarter — contributed to ratings agency Moody's decision in early December to lower its outlook for the company from "stable" to "negative."

An actual downgrade in its credit rating would have made it even more expensive for Kinder Morgan to service its debt, particularly with the US Federal Reserve looking increasingly likely to raise US interest rates in the near future.

Kinder Morgan's stock price had also lost roughly a third of its value over the last week, which "raised the cost of our equity to the point where it is no longer an economic source of expansion capital," said Kinder.

However, Moody's immediately changed the company's outlook back to "stable" after the announcement of the dividend cut, and Kinder Morgan's stock price closed nearly 7% higher on Wednesday.

Standard & Poor's also reaffirmed its credit rating of "BBB-" after Kinder Morgan's decision to reduce its payout to shareholders.

"The rating action reflects our view that [Kinder Morgan's dividend adjustment is credit positive and a prudent and necessary action taken by management in light of very challenging capital market conditions," said S&P analyst Michael Grande.

"The move eliminates nearly all of the company's funding risk headed into 2016," he added.

Kinder Morgan said the dividend cut will enable it to fund its entire $3.8 billion growth budget in 2016 — as well as make significant payments on its debt — using only its cash flow, which is expected to exceed $5 billion next year.

The company said it believes it can also pay for its 2017 and 2018 growth spending without tapping into equity markets

"By reducing our distributions, we will have more than enough money to meet our expansion capital needs and to manage our debt consistent with investment grade metrics," Kinder said. "We can truly control our own destiny."

Chris Raine, New York

January ...

(continued from page 1)

ment is so pervasive that any attempt to rally on a bullish development is reversed by the entrenched "sell any rally" mindset that has taken hold.

An EcomEnergy analysis noted that the only glimmer of hope for a price recovery right now is a tendency for the prompt month to peak around the 15th of the month. However, even that technical driver could be run over this month after cash prices in the eastern US saw a solid dive to multi-year lows last week. By Friday, benchmark pricing at the Henry Hub fell to $1.76 — the lowest since 2001. Algonquin citygate fell to $1.08, while Transco Zone 6 New York sank to 91¢. In the Upper Mid-

(continued on page 14)

PIPELINE CAPACITY UTILIZATION

(Mcf/d)

Location	FlowDate	Flow	Dec (2014) Month-to-Date	Dec (2015) Month-to-Date
ANR LA	12/5/2015	--	--	--
ANR OK	12/5/2015	606,274	637,483	698,684
Chicago Citygate	12/5/2015	2,363,013	2,509,839	3,285,555
Florida	12/5/2015	3,056,674	3,356,160	2,726,239
Michcon	12/5/2015	1,085,431	997,479	917,663
NGPL TexOk	12/5/2015	622,857	541,003	477,938
Niagara	12/5/2015	--	--	--
NNG Demarc	12/5/2015	--	--	--
Opal	12/5/2015	870,000	854,567	906,765
PEPL Haven	12/5/2015	1,012,241	915,053	1,174,632
PG&E citygate	12/5/2015	2,846,000	3,105,800	2,646,000
PG&E Malin	12/5/2015	1,118,669	1,083,727	1,113,918
Questar	12/5/2015	1,302,086	1,570,180	1,499,934
SoCal	12/5/2015	2,603,000	3,110,800	2,968,800

BENTEK Energy LLC

www.bentekenergy.com

CNG Makes Fresh Inroads Into Passenger Cars

With the departure of the Honda Civic Natural Gas earlier this year (NGW Jul.13'15), the rise of electric vehicles and a race toward fuel cells, the natural gas vehicle passenger market might seem a lost cause. However, compressed natural gas (CNG) has now found its way into a nearby market segment — pickup trucks, specifically the Ford F-150. CNG is also moving up the passenger car value chain, becoming a fuel choice for the trucks that carry car parts to assembly plants and those that carry the finished vehicles to dealerships.

Last week, Ford announced that the first 2016 F-150 capable of running on CNG or propane, rolled off the assembly line at the company's Kansas City Assembly Plant. The F-150 with a 5.0-liter Ti-VCT V8 engine is available with a factory-installed, gaseous-fuel prep package that includes hardened valves, valve seats, pistons and piston rings so it can operate on natural gas, propane or gasoline through separate fuel systems.

Ford said that when equipped with a bi-fuel CNG/propane engine package, the truck can run more than 750 miles on combined tanks of gasoline and CNG, depending on tank size and is estimated to get 22 miles per gallon on the highway and 18 mpg combined. Last year, Ford added an all-aluminum body for the F-150, which reduces the weight of the truck by about 700 pounds.

But what of the upfront incremental cost of the CNG/propane capable engine package? The factory engine prep costs only $315, but the customer will still have to pay a "Ford Qualified Vehicle Modifier" for an upfit costing from $6,000 to $9,500 depend on fuel tank capacity.

Ford boasts of having sold more than 60,000 vehicles "prepped" — though not necessarily running — on natural gas and propane, or six times the amount sold by all other US automakers combined since 2009. Including the F-150, Ford now offers eight trucks with a factory-added gaseous-fuel prep option.

And while smaller passenger vehicles aren't generally headed toward CNG, they are likely to be headed toward dealerships on carriers powered by CNG.

California-based TruStar Energy last week completed construction of a private CNG fueling station for Michigan-based FCA US — a unit of Fiat Chrysler Automobiles, which sells Fiat, Chrysler, Jeep, Dodge and Ram brands. Located at FCA's North American Detroit terminal, the station will fuel 179 tractor trucks in FCA Transport's fleet. Six compressors will be available to dispense 40 gasoline-gallon equivalent per minute at what will now be the largest private fast-fill station in the US.

The FCA Transport fleet delivers automobile parts and materials to assembly plants in Ontario, Michigan and Ohio.

"Allocating FCA US resources to convert the fleet to CNG not only yields the company long-term cost savings, it significantly reduces CO2 emissions and continues the company's leadership in the areas of technological advancement and sustainability," said Marty DiFiore, head of FCA Transport.

And there is a green benefit.

"Even in a lower oil price environment, certain CNG applications still make economic sense providing significant cost savings while allowing corporations to make progress toward sustainability goals," said Adam Comora, president of TruStar Energy, which will own, operate and supply CNG to the station under a long-term supply contract.

Further down the value chain, South Carolina-based Mainstay Fuel Technologies has delivered 30 custom-designed CNG fuel systems for use by CNG-powered car haulers. Virginia Transportation, based in Rhode Island, serves major car manufacturers including Honda, Toyota, Mercedes, Ford, Volkswagon, Nissan and BMW. The company also hauls cars for Avis and Enterprise rent-a-car companies.

The new CNG-powered fleet will be used in collaboration with Honda, moving vehicles from Honda's Lincoln, Alabama factory to a CSX rail facility.

Mainstay's fuel system uses a dual side-mounted alignment with two Type IV CNG cylinders. Peterbilt altered the cab and chassis of its 365 Daycab to accommodate the fuel system. "The cylinder size and durability were critical in this project in order to meet the car hauler's range requirements and clearance restraints," said Mainstay Technical Director David Benner.

Michael Sultan, Washington

COMPARATIVE FUEL PRICES

(Cash Market)

December 11, 2015

APPALACHIA

Appalachian Pool Dlvd (Util)	Ohio/Big Sandy River Coal
	$43.21/ton
$1.44/MMBtu	$1.80/MMBtu

EAST COAST

New York City Gate	Heating Oil No. 2*	Residual 0.30%	Residual 1.00%
	107.49¢/gal	$35.71/bbl	$25.03/bbl
$1.19/MMBtu	$7.75/MMBtu	$5.68/MMBtu	$3.98/MMBtu

GULF COAST

Natural Gas Texas Onshore Dlvd (Util)	Natural Gas Louisiana Onshore Dlvd (Util)
$1.94/MMBtu	$1.90/MMBtu

Heating Oil No. 2*	Residual 0.70%	Residual 3.00%	WTI Cushing
$103.89/bbl	$30.78/bbl	$23.78/bbl	$36.93/bbl
$7.49/MMBtu	$4.90/MMBtu	$3.78/MMBtu	$6.37/MMBtu

Notes: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content. *Average sulfur content = 0.2%-0.5%.

Sources: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of The Oil Daily's cash price postings.

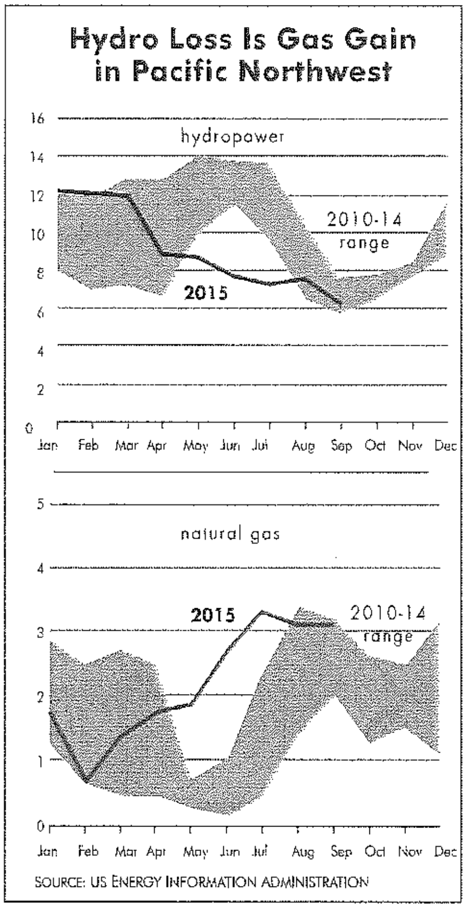
Pacific Northwest Uses Gas to Cover Low Hydro Levels

The Pacific Northwest has gotten some badly needed drought relief from major storms systems that have been pounding the region lately. But the warm, dry 2014-15 winter was far different and dramatically stepped up natural gas and other fossil fuel demand when hydro failed, according to the US Energy Information Administration.

Hydroelectric generation in the Pacific Northwest fluctuates throughout the year and usually peaks during the spring when the winter accumulation of snowpack melts, filling the reservoirs that power hydroelectric plants.

However, the warmer winter caused most mountain precipitation to fall as rain instead of snow, reducing the formation of snowpack. Washington and Oregon snowpack in May was just 16% and 11% of 30-year norms, respectively. And increased winter rainfall shifted the hydro peak from spring to winter. And summer hydroelectric generation was 32% lower than the average of the previous five summers.

As a result, natural gas power in May exceeded the range from the previous five years, and in July reached 3.3 million megawatt hours — a 53% increase over July 2014, according to the Energy Information Administration (EIA).



Despite recent storms and increasing snowpack in the mountains, the expected El Nino cycle may further complicate weather impacts on electricity generation during the coming months by extending the pattern of warmer, drier weather, the EIA said. Which means the region could again see earlier-than-anticipated hydroelectric generation followed by increased natural gas generation in the spring and summer.

Furthermore, El Nino conditions could continue into 2016, according to the National Oceanic and Atmospheric Administration (NOAA) forecast.

NOAA's three-month seasonal outlook for December through February indicates a high probability of above-average temperatures in the Pacific Northwest and coastal regions of California.

The EIA report shows the Columbia River Basin, which feeds many of the hydroelectric dams in Washington and Oregon, largely falls in a higher-temperature, lower-precipitation outlook area. Greater precipitation may be expected in Southern California, but fewer than half of California's reservoirs are located in the southern part of the state.

NOAA's winter outlook has mixed implications for overall West Coast hydroelectric generation, but the trend of natural gas picking up the slack could continue.

* * *

Solar spat: South Carolina's state-owned electric and water utility, Santee Cooper, approved a package of controversial solar energy charges last week that the utility said would help it recover lost revenue. Critics, however, say that the new charges will discourage interest in solar power in the state.

The Santee Cooper board approved charging customers who install solar panels to heat and light their homes. All Santee Cooper customers will see their rates increase by an average of 3.7 % over each of the next two years as part of a $2.7 billion budget approved last week by the board of directors.

Officials say Santee Cooper's solar levies are being assessed in part to offset the cost of providing utility lines and other equipment to solar customers, as well as to pay off debt.

The solar standby fee should cost residential customers $4.40 per month per kilowatt of installed solar capacity, which would be about $17 per month for the average residential solar-equipped customer, according to Santee Cooper.

Santee Cooper also would charge customers who want to sell the utility their excess solar power a monthly metering fee and a standby charge ranging between $4.20 and $4.70 per kilowatt per month. The standby charge covers the cost of the infrastructure needed so the customer can access the grid.

Santee Cooper offers an incentive to buy excess solar power from residential customers at 7¢ per kilowatt hour, which is less than the utility's retail rate for household consumers of about 11¢/kWh. The company also has rebates for people who invest in rooftop solar.

Nonetheless, skeptics maintain that the additional charged imposed on residential solar customers is punitive and reduces the benefit of smaller power bills.

Lisa Lawson, Houston

SPOT ELECTRICITY TRADING

Trading Dates: December 7-December 11, 2015

POINT	Avg. Price This Week	Avg. Price Last Week	Change	Year Ago	Month Ago
COB	$20.20	$26.00	-$5.80	$30.75	$30.55
ERCOT	27.00	28.80	-1.80	32.50	26.73
Mid-Columbia	17.60	24.00	-6.40	27.25	27.55
NEPOOL	24.60	29.00	-4.40	39.75	28.55
Palo Verde	19.20	20.60	-1.40	30.00	24.00
PJM-West	27.60	30.80	-3.20	39.50	29.27

Notes: (1) Prices in $/MWh. (2) Prices are for next day peak delivery. Sources: Staff and wire reports.

Phillips 66 Puts Sweeny Complex NGLs Fractionator Into Operation

Phillips 66 has begun operations at its new 100,000-barrel per day natural gas liquids fractionator at the company's Sweeny Complex in Old Ocean, Texas.

Sweeny Fractionator One supplies purity ethane and liquefied petroleum gas (LPG) to the petrochemical industry and heating markets. It is supported by 250 miles of new pipelines and a multimillion barrel storage cavern complex.

Fractionator operations were originally expected to start in early October, but the start was delayed by mechanical problems with a furnace.

The LPG produced at Sweeny Fractionator One are being delivered via pipeline to local petrochemical customers, as well as to the market hub at Mont Belvieu, Texas. Phillips 66 also will export LPG upon completion of its 150,000 b/d Freeport LPG Export Terminal in the second half of 2016.

Phillips 66 owns fractionation capacity at multiple fractionators in Mont Belvieu and Conway, Kansas.

Sweeny Fractionator One and the Freeport LPG Export Terminal represent a combined capital investment of more than $3 billion.

* * *

In other industry news: SoCalGas crews began drilling a relief well on Dec. 4 to intercept and plug a leaking natural gas access well at its Aliso Canyon natural gas storage facility in the Santa Susana Mountains of California's San Fernando Valley.

The leaking well is one of about 100 injection and withdrawal wells at the facility. Plugging the leak, discovered Oct. 23, will take about three to four months, but it poses little hazard due to its distance from area homes, SocalGas said.

* * *

TransCanada's Coastal GasLink Pipeline Project has signed long-term project agreements with the Burns Lake Indian Band, Blueberry River First Nations and Lheidli T'enneh First Nation. The proposed 415-mile Coastal GasLink Pipeline runs from the Dawson Creek area of British Columbia to Kitimat on the Pacific Coast. The project is a key component of TransCanada's capital growth plan, which includes more than $13 billion in proposed pipeline projects to support LNG exports from British Columbia.

* * *

Advanced Power AG has filed with the Ohio Power Siting Board to build the 1,105-megawatt natural gas-fired South Fork power plant near Wellsville, Ohio. The $1.1 billion project, the fifth natural gas-fired plant brought to the board in the past two years, could be in service in 2020.

Legal & Legislative:

Pennsylvania Attorney General Kathleen Kane has filed a lawsuit against Chesapeake Energy, claiming the company cheated thousands of landowners who signed drilling leases with the company. The lawsuit alleges Chesapeake tricked landowners into signing one-sided leases in the early years of the Marcellus Shale drilling boom and then improperly deducted post-production expenses from landowner royalties. The suit is seeking unspecified restitution and civil penalties. A Chesapeake spokesman called Kane's allegations baseless.

* * *

Two companies are asking an Oklahoma state judge to dismiss a lawsuit naming them and 25 other parties. The suit — filed by Prague, Oklahoma resident Sandra Ladra who was injured in a 2011 5.6 magnitude earthquake that she claims was caused by wastewater injection wells — was originally dismissed by Lincoln County District Judge Cynthia Ferrell Ashwood. That ruling was overturned by the state Supreme Court (NGW Jul.6'15). Spess Oil and New Dominion argue that the action could hurt Oklahoma's energy industry and that Ladra waited too long to file suit.

Financial News:

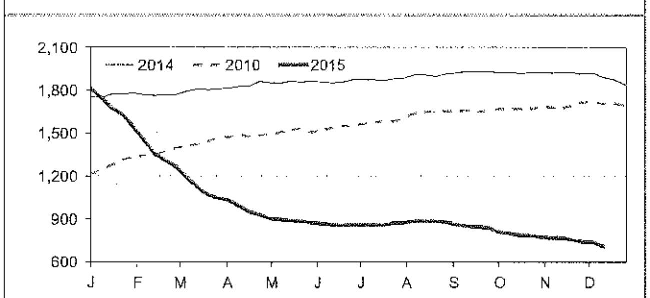
Energy & Exploration Partners has become the 18th drilling company in Texas to seek Chapter 11 bankruptcy protection. Already hit by low oil and natural gas prices, the company was cut off from its core fields near the Trinidad River in Texas by massive spring floods — reducing its production by half for more than a year. The company has cut 15 of its 59 workers and its chief operating officer, top acquisition and divestiture coordinator, chief accounting officer and chief financial officer have resigned. In its filing,

(continued on page 11)

BAKER HUGHES RIG COUNT

Week Ended Dec. 11

Region	Current Week	Previous Week	Year Ago
Total US	**709**	**737**	**1,893**
Land	686	710	1,820
Gulf of Mexico	23	25	58
Total Canada	**174**	**177**	**431**
US Rigs Exploring for:			
Oil	524	545	1,546
Gas	185	192	346
Unspecified	0	0	1
Drilling Direction			
Directional	64	64	196
Horizontal	554	569	1,367
Vertical	91	104	330
US Rigs by State:			
California	9	9	45
Colorado	25	27	68
Louisiana	60	60	113
New Mexico	36	40	101
North Dakota	58	60	179
Ohio	15	19	47
Oklahoma	85	84	211
Pennsylvania	30	29	54
Texas	324	333	872
Wyoming	21	22	58
Major Oil Basins*			
Cana Woodford	37	35	43
DJ Niobrara	23	25	60
Eagle Ford	76	73	204
Permian	204	217	548
Williston (Bakken)	58	60	188
Major Gas Basins*			
Marcellus	42	42	83
Haynesville	27	28	43



(continued from page 10)
Energy & Exploration Partners said it had roughly $500 million in assets and more than $1 billion in liabilities,

* * *

Lola Energy, a newly formed independent oil and gas company, has closed on a $250 million equity commitment from Denham Capital. Lola will use the equity funding to focus on the Marcellus and Utica Shales, where it has started acquiring core-area properties for horizontal oil and gas development.

* * *

Fluor is buying the Netherlands' Stork Holding from United Kingdom-based Arle Capital Partners for $755 million. Irving, Texas-based Fluor said it will keep the Stork brand name and most of its leadership. Fluor is an energy engineering and construction firm, while Stork focuses more on operating and maintaining major energy and petrochemical plants.

Also Noted:

CEOs picked: HollyFrontier has named George Damiris president and chief executive officer; NRG Yield has named Mauricio Gutierrez interim president and CEO following the departure of CEO David Crane; Connacher Oil and Gas has named Chief Operating Officer Merle Johnson CEO; Renewable Energy Trust Capital has named Karen Morgan CEO; and Thermon Group Holdings CEO Rodney Bingham is retiring and will be replaced by Bruce Thame.

* * *

Officers named: Calgon Carbon has named Chad Whalen general counsel and secretary; Envirosystems has named Kent S. Bartley chief operating officer; Ensco COO Mark Burns is retiring and will be replaced by Carey Lowe; and PPL has named Joseph P. Bergstein Jr. vice president-Investor Relations and treasurer.

GAS PRICE TRENDS

($/MMBtu)

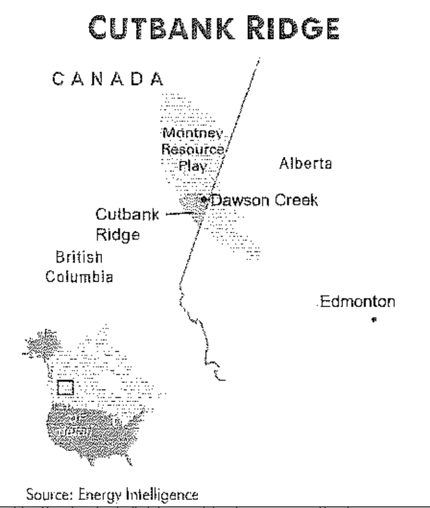
	CALIFORNIA		ROCKY MTNS	NEW MEXICO	TEXAS				MID-CONT.	LOUISIANA			MID-WEST	APPA-LACHIA	SOUTH-EAST	NEW ENG.
	South	North			Gulf Coast Offshore	Central Onshore	Central	West		Gulf Coast Offshore	Gulf Coast Onshore	Northern Louisiana				
Dec 14, 2015																
Inter (Well)	—	—	1.71	1.71	1.77	1.71	—	1.75	1.66	1.68	1.72	1.75	—	1.25	1.68	—
Intra (Well)	2.04	—	1.68	—	1.78	1.73	—	1.75	1.64	1.68	1.72	1.74	—	—	—	—
Dlvd (Pipe)	2.06	2.18	1.83	1.88	1.84	1.79	—	1.82	1.76	1.75	1.79	1.82	1.82	1.36	1.83	1.19
Dlvd (Util)	2.06	2.16	2.16	2.03	—	1.94	—	1.90	2.01	—	1.90	1.96	1.84	1.44	2.28	1.38
Dec 07, 2015																
Inter (Well)	—	—	2.00	2.00	2.04	2.04	—	2.04	1.99	1.99	2.01	2.00	—	1.49	2.00	—
Intra (Well)	2.24	—	1.97	—	2.05	2.06	—	2.04	1.97	1.99	2.01	1.99	—	—	—	—
Dlvd (Pipe)	2.26	2.41	2.12	2.17	2.11	2.12	—	2.11	2.09	2.06	2.08	2.07	2.13	1.60	2.15	1.85
Dlvd (Util)	2.26	2.40	2.45	2.32	—	2.27	—	2.19	2.34	—	2.19	2.21	2.15	1.68	2.56	2.31
November 2015																
Inter (Well)	—	—	1.98	1.86	1.94	1.94	—	1.93	1.92	1.93	1.95	1.94	—	1.52	1.92	—
Intra (Well)	2.16	—	1.95	—	1.95	1.96	—	1.93	1.90	1.93	1.95	1.93	—	—	—	—
Dlvd (Pipe)	2.18	2.43	2.10	2.03	2.01	2.02	—	2.00	2.02	2.00	2.02	2.01	2.14	1.63	2.07	2.25
Dlvd (Util)	2.18	2.40	2.43	2.18	—	2.17	—	2.08	2.27	—	2.13	2.15	2.15	1.71	2.51	3.33
October 2015																
Inter (Well)	—	—	2.06	2.02	2.16	2.20	—	2.14	2.10	2.20	2.21	2.18	—	1.63	2.16	—
Intra (Well)	2.37	—	2.03	—	2.17	2.22	—	2.14	2.08	2.20	2.21	2.17	—	—	—	—
Dlvd (Pipe)	2.39	2.55	2.18	2.19	2.23	2.28	—	2.21	2.20	2.27	2.28	2.25	2.36	1.74	2.31	2.64
Dlvd (Util)	2.39	2.48	2.51	2.34	—	2.43	—	2.29	2.45	—	2.39	2.39	2.35	1.82	2.75	3.75
Third Quarter 2015																
Inter (Well)	—	—	2.48	2.45	2.61	2.61	2.67	2.56	2.54	2.62	2.64	2.61	—	1.94	2.60	—
Intra (Well)	2.80	—	2.45	—	2.62	2.63	2.67	2.56	2.52	2.62	2.64	2.60	—	—	—	—
Dlvd (Pipe)	2.82	2.95	2.60	2.62	2.68	2.69	2.76	2.63	2.64	2.69	2.71	2.68	2.78	2.05	2.75	1.98
Dlvd (Util)	2.82	2.93	2.93	2.77	—	2.84	2.93	2.71	2.89	—	2.82	2.82	2.80	2.13	3.16	2.61
Second Quarter 2015																
Inter (Well)	—	—	2.36	2.29	2.58	2.56	2.57	2.42	2.42	2.59	2.61	2.57	—	1.97	2.59	—
Intra (Well)	2.57	—	2.33	—	2.59	2.58	2.57	2.42	2.40	2.59	2.61	2.56	—	—	—	—
Dlvd (Pipe)	2.59	2.94	2.48	2.46	2.65	2.64	2.66	2.49	2.52	2.66	2.68	2.64	2.68	2.08	2.74	2.00
Dlvd (Util)	2.59	2.90	2.81	2.61	—	2.79	2.83	2.57	2.77	—	2.79	2.78	2.70	2.16	3.17	2.23
First Quarter 2015																
Inter (Well)	—	—	2.47	2.47	2.65	2.66	2.59	2.60	2.76	2.74	2.80	2.77	—	2.39	2.75	—
Intra (Well)	2.73	—	2.44	—	2.66	2.68	2.59	2.60	2.74	2.74	2.80	2.76	—	—	—	—
Dlvd (Pipe)	2.75	2.83	2.59	2.64	2.72	2.74	2.68	2.67	2.86	2.81	2.87	2.84	3.27	2.50	2.90	6.53
Dlvd (Util)	2.75	2.82	2.92	2.79	—	2.89	2.85	2.75	3.11	—	2.98	2.98	3.30	2.58	3.29	10.40
2014 Average																
Inter (Well)	—	—	4.07	4.11	4.06	4.20	4.37	4.08	5.27	4.26	4.21	4.25	—	3.58	4.21	—
Intra (Well)	4.25	—	4.04	—	4.07	4.22	4.37	4.08	5.25	4.26	4.21	4.24	—	—	—	—
Dlvd (Pipe)	4.27	4.75	4.19	4.28	4.13	4.28	4.46	4.15	5.37	4.33	4.28	4.32	6.72	3.69	4.36	5.67
Dlvd (Util)	4.27	4.66	4.52	4.43	—	4.43	4.63	4.23	5.62	—	4.39	4.46	6.99	3.77	4.72	7.25
December 2014																
Inter (Well)	—	—	3.13	3.09	3.23	3.04	2.57	2.98	3.11	3.06	3.18	3.00	—	2.69	3.14	—
Intra (Well)	3.44	—	3.10	—	3.24	3.06	2.57	2.98	3.09	3.06	3.18	2.99	—	—	—	—
Dlvd (Pipe)	3.46	3.56	3.25	3.26	3.30	3.12	2.66	3.05	3.21	3.13	3.25	3.07	3.46	2.80	3.29	3.23
Dlvd (Util)	3.46	3.51	3.58	3.41	—	3.27	2.83	3.13	3.46	—	3.36	3.21	3.43	2.88	3.73	5.50

Notes: (1) Inter = Interstate Intra = Intrastate Well = Wellhead Dlvd = Delivered Pipe = Pipeline Util = Utility (2) This table presents historical data from the Gas Price Report. (3) R = Revised. (4) Mid-Cont. = Miontinent New Eng. = New England (5) Since Jan. 3, 1994, California prices have been divided into North to reflect gas delivered from Pacific Gas Transmission Co. to northern California and South to reflect gas delivered to southern California via the Transwestern Pipeline Co., El Paso Natural Gas Co. and Kern River Gas Transmission pipeline systems. Previous reporting for the state concentrated on southern California; thus, the historical prices in the South column properly reflect trading for southern California. Natural Gas Week has no similar history of prices for northern California. (6) All prices are volume-weighted. (7) The price points that made up the "Texas Central" and "Texas Gulf Coast, Onshore" composites in the Gas Price Trends table have been incorporated into the new "Texas Central Onshore" composite. The "Texas Central" composite will be eliminated.

Veresen OKs Gathering System near Montney Play

Calgary-based Veresen has begun work on the C$715 million (US$525 million) Tower natural gas processing complex in northeastern British Columbia after getting a green light to proceed from local gas producers — Canada's Encana and Japan's Mitsubishi, partners in the huge Cutbank Ridge development in British Columbia's prolific Montney Shale.

Midstream specialist Veresen agreed last year to undertake up to C$5 billion worth of expansion projects for Encana including the Cutbank Ridge development. According to Veresen, the Tower complex south of Fort St. John, British Columbia will be able to process 200 million cubic feet per day of natural gas and up to 20,000 barrels per day of condensate and natural gas liquids (NGLs) when it becomes operational in 2017.



Source: Energy Intelligence

Veresen Midstream will fund 55% to 60% of Tower's construction costs with its existing $1.275 billion credit facility, which is largely undrawn, with the balance to be contributed over time by Veresen and KKR. Veresen Midstream will be Veresen's primary growth vehicle for its Canadian natural gas and NGLs midstream business.

The Tower complex — which will be fully owned and controlled by Veresen — includes a processing plant as well as storage and other facilities. The green light for Tower follows a previously announced plan to build the C$860 million Sunrise natural gas plant near Dawson Creek, British Columbia. Sunrise is expected to process some 400 MMcf/d of gas.

Both processing plants would handle natural gas from the prolific Montney Formation in northeastern British Columbia and are part of the Veresen Midstream Limited Partnership. Veresen now has C$1 billion worth of growth projects under construction, including the Tower and Sunrise gas plants, the Burstall ethane storage facility and the Aux Sable fractionation expansion — all located in Western Canada.

In addition, construction of the 40-megawatt Grand Valley Wind Farm Phase III in Ontario has been completed ahead of schedule and under budget. The project was placed into operation last week.

The Montney remains Western Canada's most actively developed gas resource play and continues to deliver strong results even against a challenging macro environment. The Montney recently hit production output of nearly 500,000 barrels of oil equivalent per day, while the next big new play in Western Canada — the deeper, less cost-effective Duvernay play in Alberta — lags behind at just 73,000 boe/d.

According to oil and gas consultancy Wood Mackenzie, the Montney alone now accounts for 30% of the gas production coming out of the Western Canadian Sedimentary Basin. Of the two plays, the Montney has more resources, according to Woodmac, at about 30 billion boe, compared with the Duvernay's 13 billion boe (NGW Nov.23'15).

Last year, Encana Chief Executive Doug Suttles said Cutbank Ridge had a supply cost of $2.69 per million Btu — about 20% better than its peer group average.

Plays like the Montney have the same resource potential as US juggernauts like the Marcellus. The British Columbia government, for example, forecasts that the Montney alone contains enough gas to satisfy current Canadian gas demand for 145 years.

A report by BMO Capital Markets says the Montney also holds the highest oil in place among established tight oil plays, "although relatively little of this is expected to be recovered using current technology."

In 2012, Encana struck a joint-venture deal worth C$2.9 billion with Japanese industrial giant Mitsubishi for a 40% stake in its Cutbank Ridge unconventional gas properties in northern British Columbia. The deal followed the collapse of a similar arrangement with PetroChina in the summer of 2011 (NGW Apr.23'12).

Veresen plans to build the Jordan Cove LNG export terminal at Coos Bay, Oregon, but is also positioning itself should a LNG export boom transpire in British Columbia, especially since it would be underpinned by gas found in the Montney and Horn River Shales.

* * *

Rig count: There were 177 rigs drilling for natural gas and oil in Western Canada as of Dec. 7, two fewer rigs than reported for the previous week by the Canadian Association of Oilwell Drilling Contractors (CAODC).

During the same period a year ago, CAODC said 420 rigs were drilling in the region.

A total of 763 rigs are available in the region, unchanged from CAODC's previous report.

* * *

Working gas in all Canadian storage facilities was reported to be 88% of capacity as of Dec. 4 with a 6 billion cubic foot withdrawal from the week before, according to the most recent Canadian Enerdata gas storage survey.

A total of 676.3 Bcf of gas was in storage last week; capacity is 768.7 Bcf. Stores were 73.4% full a year ago.

Working gas levels in facilities west of the Manitoba-Saskatchewan border fell to 410.6 Bcf, down from a revised 415.8 Bcf the week before; capacity is 489.7 Bcf.

Working gas levels east of the border fell to 265.7 Bcf, down from 266.5 Bcf the week before; capacity is 279 Bcf.

* * *

The composite spot import price this week is US$1.75/MMBtu for gas leaving Canada and entering the US through six border-crossing points.

Natural Gas Week's Dec. 15, 2014, average for Canadian exports was US$3.69/MMBtu.

James Irwin, Toronto

Russian Global Gas Market Role Seen Shrinking

Russia's role in the global gas market is expected to shrink in the next two decades, experts warn. Both in its traditional European export market and its emerging Asian market, Russia will have to adapt to increased competition and fight to sustain its position, while geopolitics will also factor significantly.

Geopolitics is already affecting plans of Russian state-run gas giant Gazprom to increase and reroute supplies to Europe. The bitter crisis in relations with Turkey resulted in the Turk Stream project being frozen, while the 55 billion cubic meters per year Nord Stream-2 pipeline project is facing strong opposition from a number of EU countries as well as from Brussels, let alone Ukraine and the US. The future of Nord Stream-2 is expected to be discussed at this week's EU summit.

BP's head of Russia & CIS economics, Vladimir Drebentsov, told an industry conference in Moscow that Europe's gas markets are going through major changes and the perception of Gazprom as the dominant supplier is likely to be reconsidered.

Gazprom is confident it can remain a key gas supplier to Europe in the long term, as the EU's indigenous production is set to fall by 7.7 billion cubic feet per day in the next 15 years. However, Drebentsov said, Gazprom should be prepared to cut production costs in order to offer competitive pricing.

US LNG supplies could become a mainstay in the European market within two years. Also, there could be growing competition with Iranian gas as Western sanctions are lifted.

Vitaly Sokolov, Moscow

CANADIAN PRICE REPORT

($US/MMBtu and $Can/MMBtu)

	BRITISH COLUMBIA			ALBERTA		MANITOBA	ONTARIO	
	Total Province	NW Sumas Border	Kingsgate Border	AECO Hub	Empress Border	Emerson Border	Dawn Hub	Niagara
DECEMBER 14, 2015								
Wellhead U.S. $	1.69	—	—	—	—	—	—	—
Canadian $	2.35	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	1.83	1.88	1.78	1.53	1.70	1.88	1.87	1.15
Canadian $	2.49	2.55	2.42	2.07	2.31	2.55	2.54	1.56
DECEMBER 7, 2015								
Wellhead U.S. $	1.95	—	—	—	—	—	—	—
Canadian $	2.65	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.09	2.21	1.96	1.60	1.78	2.12	2.17	—
Canadian $	2.79	2.95	2.62	2.13	2.38	2.83	2.91	—
NOVEMBER 2015 AVERAGE								
Wellhead U.S. $	2.02	—	—	—	—	—	—	—
Canadian $	2.72	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.16	2.22	2.09	1.79	1.85	2.16	2.21	1.85
Canadian $	2.86	2.95	2.77	2.38	2.46	2.86	2.94	2.46
OCTOBER 2015 AVERAGE								
Wellhead U.S. $	1.98	—	—	—	—	—	—	—
Canadian $	2.63	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.12	2.13	2.10	1.89	2.02	2.47	2.61	1.88
Canadian $	2.77	2.79	2.74	2.47	2.65	3.24	3.41	2.46
3RD QUARTER 2015 AVERAGE								
Wellhead U.S. $	2.29	—	—	—	—	—	—	—
Canadian $	3.04	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.43	2.43	2.43	2.10	2.28	2.76	3.00	1.88
Canadian $	3.18	3.17	3.18	2.74	2.99	3.61	3.92	2.45
2ND QUARTER 2015 AVERAGE								
Wellhead U.S. $	2.15	—	—	—	—	—	—	—
Canadian $	2.68	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.29	2.24	2.34	2.10	2.34	2.76	2.88	1.89
Canadian $	2.82	2.76	2.87	2.58	2.87	3.39	3.54	2.33
1ST QUARTER 2015 AVERAGE								
Wellhead U.S. $	2.32	—	—	—	—	—	—	—
Canadian $	2.91	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.46	2.52	2.39	2.12	2.78	3.23	3.48	4.70
Canadian $	3.05	3.13	2.96	2.63	3.45	4.00	4.31	5.82
2014 AVERAGE								
Wellhead U.S. $	4.16	—	—	—	—	—	—	—
Canadian $	4.60	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	4.30	4.36	4.14	3.58	3.99	4.77	4.83	3.82
Canadian $	4.74	4.81	4.57	3.95	4.41	5.26	5.33	4.22
DECEMBER 2014 AVERAGE								
Wellhead U.S. $	3.24	—	—	—	—	—	—	—
Canadian $	3.76	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	3.38	3.31	3.46	2.59	3.19	3.44	3.69	—
Canadian $	3.90	3.81	3.99	2.99	3.68	3.97	4.26	—

NOTES: Prices are in $US/MMBtu and $Canadian/MMBtu. Monetary conversions are done weekly. All prices represent volume-weighted averages for the most recent Monday-Sunday trading week. R=Revised.

January ...

(continued from page 7)

west, the Chicago citygates fell to $1.74, the lowest since 2007.

And until cold weather demand ramps up — and that may be delayed for another two weeks — there's little reason for cash prices to see much of a recovery. And that is especially bad for producers, who increasingly lack protection from hedges.

The US Energy Information Administration reported a draw of 76 billion cubic feet for the week ended Dec. 4, bringing the amount of working gas in storage to 3,880 Bcf. The build exceeded analysts' consensus estimates by around 12 Bcf and unexpectedly beat the five-year average pull of 65 Bcf, reducing the five-year average surplus to 236 Bcf, or 6.5% above the average.

But while futures first jumped, they then crashed as murky market direction gets increasingly inscrutable. The slide continued Friday with January futures ending the week 2.5¢ lower at $1.99/MMBtu, down 19.6¢, or 9%, for the week. Gelber & Associates analyst Aaron Calder noted it was the first $1 handle seen on a Nymex contract since 2012 and the first during winter in 17 years.

And storage will continue to weigh heavy as early estimates for this week's withdrawal are averaging in the low 40s Bcf, a third of the 120 Bcf five-year average.

In any case, this week's ostensibly bullish storage data might stem from bearish fundamentals.

"End-users are using proportionally more stored gas than they usually do because there is little downside in doing so," Calder said. "Low futures prices means they don't need to keep stored gas as a hedge against high prices, and there may be penalties for not using all of their stored gas before winter is over."

More bearish news came from *Natural Gas Week* data showing gas demand, if it were to replace off-line nuclear capacity, falling to an average just below 2 Bcf/d last week, compared to 2.69 Bcf/d for the previous week.

Baker Hughes reported the Lower-48 gas-directed rig count was down by seven, bringing the total to 185 rigs.

January WTI crude fell $1.14 Friday to $35.62/bbl, down $4.35, or 10.9%, for the week. Meanwhile, Baker Hughes reported oil-directed rigs were down by 21, bringing the total to 524.

The Commodity Futures Trading Commission's Commitments of Traders report for the week ended Dec. 8 showed non-commercials in 65.7% short futures-only positions for the week.

Lisa Lawson and Tom Haywood, Houston

Texas ...

(continued from page 1)

no corresponding increase in the value of that gas, though, said Karr Ingham, the economist who created the TPI for the Texas Alliance of Energy Producers (NGW Oct.5'15).

With natural gas prices in October averaging $2.31 per thousand cubic feet, the value of Texas-based natural gas actually decreased 36.7% to about $1.75 billion.

Ingham said estimated crude oil production in Texas totaled nearly 107 million barrels, about 7 million barrels (7.1%) more than in October 2014. With crude oil prices averaging $42.90/bbl, vthe value of Texas-produced crude hit $4.59 billion, 43.3% less than in October 2014.

"Amid all the chatter about when crude oil production may have peaked and rolled over in Texas and the US, the sentiment about prospects for recovery has become increasingly pessimistic — which is to say, realistic — as the year has progressed," Ingham said. "It seems the most optimistic outlooks expect the beginning of meaningful recovery to appear no sooner than the latter half of 2016.

"But we simply do not know how that will look at this point."

The downturn continues to hit energy industry workers as companies continue shedding more jobs in an effort to cut costs. In addition to that, last week Energy & Exploration Partners became the 18th Texas-based oil and gas drilling company to seek Chapter 11 bankruptcy protection this year (p10).

According to the TPI, about 250,230 Texans were employed by the energy industry in October — a decline of 17.8% from October 2014 when the numbers reached about 307,700.

In November, Ingham said that it became apparent that job losses in Texas from December 2014 to September 2015 could reach upward of 56,000 — well above earlier forecasts that said losses would be in the 40,000 to 50,000 range (NGW Nov.16'15).

Adding even more gloom to an already bleak picture was a report last week from Wells Fargo Securities that said many of these workers losing their jobs are leaving Texas.

"The Dallas Fed proposed that the sharp decline in the Texas labor force was attributable to workers who had traveled to Texas during the oil boom and had since left the state," the report said. "One piece of supporting evidence is the significant jump in the number of continuing unemployment payments the state is sending to out-of-state claimants."

The loss of workers, though, is not just limited to energy producing states such as Texas.

Last week, the *2016 Hays Compensation, Benefits, Recruitment and Retention Guide* was released in Canada. The guide showed that while many Canadian energy industry leaders are hoping for an upturn in 2016, 37% of them expect further declines in oil and gas industry activity.

The guide include 184 respondents — with the majority being based in Alberta — showed that 63% cut their workforces in 2015 and 35% said they believe more cuts are coming.

According to the Canadian survey: 58% of those responding showed a moderate to extreme skills shortage, due in larger part to a lack of training and the number of people leaving the industry; and 22% said they are doing nothing to attract new talent that will be needed when the upswing begins.

In Texas, Ingham said there is very little to be optimistic about. He said other indicators used in calculating the TPI — such as rig activity, permitting, wellhead prices and industry employment — continued declining through October.

Ingham said the TPI is not finished falling, adding "it has become apparent that the low point of 187.5 in the previous economic cycle (prior to the expansion that began in January 2010) is in jeopardy" and the TPI is "almost certain" to fall below that mark in the coming months.

"In fact, if the TPI loses at least 40% of its value — as we predicted in January — it would mark the first time the low point of a contraction falls below the nadir of the previous cycle," Ingham said. "At this point, the end of the current contraction is not known and cannot be foreseen.

"But we know this much: it will be the deepest and longest in the history of the TPI, which is based in January 1995."

John A. Sullivan, Houston

Industry ...

(continued from page 1)

Issued as an update to its 2012 rule limiting releases of ozone precursors known as Volatile Organic Compounds, the EPA's rule proposed in August seeks to cut methane leaks from new and modified oil and gas sources – including hydraulically fractured wells, pipeline compressor stations and storage facilities — by 40% to 45% below 2012 levels by 2025. The agency said the move is part of its mandate under the Clean Air Act (NGW Aug.24'15)

The EPA maintains that the benefits to health will outweigh any costs to industry and consumers. Overall, it estimates that the rule – for which the public comment period closed Dec. 4 — would add a nominal 0.007¢ per thousand cubic feet to the wellhead price in 2025.

But the Independent Petroleum Association of America (IPAA) reiterated its position that the rule would create a much bigger regulatory and cost burden on an industry that is already cutting emissions voluntarily.

"Despite incredible growth in oil and natural gas production in the US, emissions of methane — a primary component of clean-burning natural gas — have steadily declined and will continue to fall," said Lee Fuller, IPAA's executive vice president. "America's shale energy producers have cut methane emissions by 13.3% since 2008 while increasing production by a staggering 400%. Since emissions are already significantly decreasing, it raises concerns as to what the underlying target is for the EPA."

The Natural Gas Supply Association (NGSA) told the EPA that since 2005, US producers have cut methane emissions by 38% "through market-driven improvements in equipment, technology, infrastructure and best practices." NGSA called for "reliance on existing, voluntary methane emissions-reduction programs," noting that gas producers have a financial interest in limiting the loss of methane it can sell as a commodity.

And the Interstate Natural Gas Association of America (Ingaa), which represents pipelines, said the rule would add costs and regulatory uncertainty.

"Ingaa believes the EPA's cost-benefit analysis did not properly consider direct and indirect costs to the [pipeline] sector for leak identification, station downtimes and repairs," the group's filing said. In addition, "the EPA may not presume that all additions of compression are 'modifications' because not all additions of compressors increase fugitive emissions at a compressor station."

But a coalition of health groups that includes the American Lung Association and Physicians for Social Responsibility said the EPA rule doesn't go far enough to prevent an array of medical problems, including asthma, because it deals only with new or modified facilities. "We call on EPA to develop standards to limit similar emissions from existing sources as well, to truly protect public health," its filing said.

The Sierra Club agreed, asserting that methane "is a highly potent greenhouse gas that is 86 times as powerful as [carbon dioxide] over a 20 year time-frame — which means it is a significant contributor to climate change." The environmental group called the proposal an important step but urged the EPA to "swiftly finalize a strong standard for new sources and move quickly to propose standards to tackle existing sources of pollution."

That prospect is one of the main reasons the industry is fighting the rule. Mark Boling, Southwestern Energy's president of V+ Solutions, told a recent Washington conference that producers are especially worried about the EPA imposing limits on existing facilities, which would be a much more onerous and costly task (NGW Oct.5'15).

Meanwhile, the EDF study released last week provides some ammunition for proponents of stronger emissions standards. According to the findings, published in the *Proceedings of the National Academy of Sciences*, methane leaks in the Barnett are 90% higher than EPA inventory data indicates.

It said 30% of Barnett production sites leak more than 1% of gas they produce, which "suggests that frequent and thorough inspection and repair efforts are necessary to find and eliminate methane leaks as they arise," said EDF chief scientist Steven Hamburg, adding that the findings "can help inform the EPA's rulemaking."

From here, the agency needs to "address emissions from existing sources that will still be contributing to the overwhelming majority of emissions in the coming years," he said. "The EPA's work is not over."

Mark Davidson, Washington

Natural Gas Week is published every Monday by Energy Intelligence, Houston Tel.: 1 (713) 222-9700. Fax: 1 (713)222-2948. Washington Tel.: 1 (202) 662-0700. Fax: 1 (202) 783-8230. For subscription information, address changes and other customer service, call the Circulation Department in New York, N.Y., Tel.: 1 (212) 532-1112, Fax: 1 (212) 532-4479.

Boundary Dam CCS Project Hasn't Been on as Rosy a Road as Touted

One of the great hopes in combating climate change is that carbon capture and sequestration, or CCS, technology will allow a carbon-constrained future to continue burning natural gas and coal for power generation by capturing a significant amount of the carbon dioxide (CO2) emissions. However, while the world's first commercial-scale CCS plant — opened with great fanfare in October 2014 — has been touted as a success, recent revelations indicate that something is seriously amiss with SaskPower's Boundary Dam CCS project.

Far from living up to its hype, Boundary Dam has become mired in a host of technical and financial woes apparently hidden by political sleight-of-hand.

CCS has long been held up as the Holy Grail or a white elephant. In 2009, a University of Houston biomolecular engineering professor, the late Michael J. Economides likened CCS to a politically correct myth (NGW Sep.21'09).

For such a revolutionary project, Boundary Dam is fairly straightforward. An existing 110-megawatt coal-fired plant near Estevan, Saskatchewan, was retrofitted with equipment designed to trap around 1 million tons of CO2 annually. A portion of that captured CO2 is sold to Cenovus Energy, which uses it for enhanced oil recovery (EOR) in the nearby Weyburn oil field. The remaining CO2 is injected into a saline aquifer a mile below the surface.

However, things did not pan out so smoothly and the problems that have plagued the $1 billion project from the start have not been honestly reported by SaskPower or Saskatchewan's Conservative government. In February, a SaskPower release quoted Saskatchewan Premier Brad Wall as saying Boundary Dam was exceeding performance expectations. But in September, SaskPower put out another release saying the CCS project had captured 400,000 tons of CO2 — less than half the plant's million-ton annual capacity.

The reasons behind this apparent discrepancy were made clear in late October when the opposition New Democratic Party leaked internal SaskPower documents painting a far different picture of plant operations. As it turned out, the CCS unit had endured a number of technical problems that resulted in it being shut down for long periods. One internal memo stated the CCS unit had been operating at 45% of its rated capacity since opening and according to subsequent statements by SaskPower Chief Executive Mike Marsh, that might have been generous.

Why the different versions: "It is capable of achieving 90% capture when we have all the other pieces of equipment working," Marsh said.

Another highly touted element to the plant's success is offsetting profits from selling CO2 for EOR. But that hasn't worked out as expected. either. Because it hasn't supplied contracted volumes of CO2, SaskPower racked up C$12 million (US$8.85 million) in penalties to Cenovus last year and could owe C$5 million in penalties this year, both of which eat into the C$11 million in annual revenues being paid by Cenovus.

As for the future, the CCS unit emerged from a lengthy maintenance shutdown in early November and is said to have achieved nameplate capacity on Nov. 14-16. But at best, the plant's goal is to operate at 85% capacity and capture 800,000 tons of CO2 in 2016.

However, that could be a stretch given its history. Even if things go swimmingly, there are five- to six-day planned outages for cleaning and maintenance on the calendar every six to 10 weeks for years to come. Also, the plant will have to shut down so the acid plant — needed to capture and process sulphur dioxide — can be completed. This part of the project has been hanging fire as SaskPower wrestled with more pressing problems with the CCS unit.

But the real issue is why problems at the plant were seemingly covered up. Rolling out a complex technology is bound to entail unforeseen problems and glitches that SaskPower and the government should have aired honestly and promptly. And they should also be up front that the path ahead could be just as rocky as kinks get worked out of this very vital technology.

* * *

The *Natural Gas Week* composite spot wellhead price this week is $1.77/MMBtu, 30¢ less than last week and $1.69 less than the Dec. 15, 2014, average. The spot delivered-to-pipeline price this week is $1.64/MMBtu, 39¢ less than last week and $1.56 less than last year's corresponding average.

Tom Haywood, Houston

GAS PRICE REPORT

($/MMBtu—Spot)

December 14, 2015

	Interstate Wellhead		Intrastate Wellhead		Delivered To Pipeline		Delivered To Utility	
	This Week	Bid Week for Dec	This Week	Bid Week for Dec	This Week	Bid Week for Dec	This Week	Bid Week for Dec
CALIFORNIA								
South	—	—	2.04	2.39	2.06	2.41	2.06	2.41
North	—	—	—	—	2.18	2.57	2.16	2.57
ROCKY MOUNTAINS	**1.71**	**2.11**	**1.68**	**2.08**	**1.83**	**2.23**	**2.16**	**2.56**
NEW MEXICO	**1.71**	**2.02**	—	—	**1.88**	**2.19**	**2.03**	**2.34**
TEXAS								
Gulf Coast, Offshore	1.77	2.07	1.78	2.08	1.84	2.14	—	—
Central, Onshore	1.71	2.06	1.73	2.08	1.79	2.14	1.94	2.29
Central	—	—	—	—	—	—	—	—
West	1.75	2.07	1.75	2.07	1.82	2.14	1.90	2.22
MID-CONTINENT	**1.66**	**2.01**	**1.64**	**1.99**	**1.76**	**2.11**	**2.01**	**2.22**
LOUISIANA								
Gulf Coast, Offshore	1.68	2.05	1.68	2.05	1.75	2.12	—	—
Gulf Coast, Onshore	1.72	2.09	1.72	2.09	1.79	2.16	1.90	2.31
North	1.75	2.06	1.74	2.05	1.82	2.13	1.96	2.27
MIDWEST	—	—	—	—	**1.82**	**2.39**	**1.84**	**2.42**
APPALACHIA	**1.25**	**1.65**	—	—	**1.36**	**1.76**	**1.44**	**1.85**
SOUTHEAST	**1.68**	**2.07**	—	—	**1.83**	**2.22**	**2.28**	**2.67**
NEW ENGLAND	—	—	—	—	**1.19**	**3.49**	**1.38**	**5.18**

	Composite Wellhead	Delivered to Pipeline	12-Month Strip Nymex
December 14, 2015	1.77	1.64	—
2015 Outlook	2.46	2.61	—

The price points that made up the "Texas Central" and "Texas Gulf Coast, Onshore" composites in the Gas Price Report table have been incorporated into the new "Texas Central Onshore" composite. The "Texas Central" composite will be eliminated.